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Intermountain Power Project
Intermountain Generating Station

B&V Project 9255
May 23, 1983

Mr. James H. Anthony, Project Manager
Intermountain Power Project
Department of Water and Power
General Office Building, Room 931
P. O. Box 111
Los Angeles, California 90051

Attention: Mr. R. L. Nelson, Project Engineer

Gentlemen:

Enclosed are six (6) preliminary copies of our report, "Reduction of Sulfur Dioxide and Nitrogen Oxide Emissions." These copies are being forwarded for your use in your internal and informal discussions. The report will be finalized and bound after we have received your comments and/or approval. If you have any questions concerning the enclosed report, please contact D. O. Swenson (913-967-7426).

Very truly yours,

BLACK & VEATCH

Roger W. Dutton

cm
Enclosure

bcc: DOS

PRELIMINARY

INTERMOUNTAIN POWER PROJECT
INTERMOUNTAIN GENERATING STATION

REDUCTION OF SULFUR DIOXIDE AND
NITROGEN OXIDE EMISSIONS

SPECIAL REPORT

BLACK & VEATCH/consulting engineers

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1.0 INTRODUCTION

Presently the Intermountain Power Project is licensed by the state of Utah to construct and operate four 750 (net) megawatt coal-fired electric generating units near Lynndyl, Utah. It is presently being considered to reduce the station to two 750 (net) megawatt units. The State of Utah Department of Health will be reviewing the project air quality permits pertinent to a reduction to two-unit operation at the Intermountain Generating Station site.

The current Environmental Protection Agency and State of Utah Department of Health air quality requirements pertaining to the reduction and control of SO_2 and NO_x emissions are as follows.

ENVIRONMENTAL PROTECTION AGENCY REQUIREMENTS

Sulfur Dixodie Emissions Control

Each unit shall not cause sulfur dioxide to be discharged into the atmosphere at a rate exceeding the following.

- 0.150 pounds per million Btu heat input as averaged over 30 successive boiler operating days.
- 10 per cent of the potential combustion concentration (90 per cent reduction) as averaged over 30 successive boiler operating days.

Nitrogen Oxide Emissions Control

- Each unit shall not cause to be discharged into the atmosphere nitrogen oxides, expressed as NO_2, at a rate exceeding 0.550 pounds per million Btu heat input based on a 30-day rolling average.

STATE OF UTAH--DEPARTMENT OF HEALTH REGULATIONS

Sulfur Dioxide Emissions Control

- No unit shall discharge to the atmosphere sulfur as sulfur dioxide (SO_2) at a rate exceeding 0.155 pounds SO_2 per million Btu heat input as averaged over 30 successive boiler operating days.
- No unit shall discharge to the atmosphere sulfur dioxide at a rate exceeding 10 per cent of the potential combustion concentration (90 per cent reduction) as averaged over 30 successive boiler operating days.

Nitrogen Oxide Emissions Control

- No boiler unit shall discharge to the atmosphere nitrogen oxides expressed as nitrogen dioxide (NO_2) at a rate exceeding 0.60 pounds NO_2 per 10^6 Btu heat input based on a 30-day rolling average of successive boiler operating days. Compliance shall be accomplished by boiler design and appropriate operating practices.

This report evaluates the technological requirements and costs of further SO_2 and NO_x emission reductions. This study evaluates increasing the sulfur dioxide removal requirements from 90 per cent to 95 per cent SO_2 removal based on a 30-day rolling average. An evaluation is also made of reducing nitrogen oxide emissions to various levels, depending on the technology evaluated.

SECTION 2.0

95 PER CENT SO_2 REMOVAL

2.1 SCRUBBER MODIFICATIONS REQUIRED TO ACHIEVE 95 PER CENT SO_2 REMOVAL

The wet limestone scrubbing system purchased for the Intermountain Generating Station is designed to achieve an average SO_2 reduction of 90 per cent based on a 30-day rolling average. Ninety per cent SO_2 removal is considered to be the upper limit which scrubbers are able to achieve on a continuous basis. Wet limestone scrubbers are capable of achieving SO_2 reductions in excess of 90 per cent for short-time durations, but extended operation at these performance levels has not been demonstrated.

The major obstacle which prevents scrubbers from continuously achieving SO_2 removal efficiencies in excess of 90 per cent is the inability of the system to over scrub to make up for periods of reduced SO_2 removal rates caused by component failures, system chemistry upsets, etc. For instance, if a scrubbing system designed for 80 per cent SO_2 removal achieves only 70 per cent removal for 10 hours due to a component failure, it can then be operated at 85 per cent removal for 20 hours and still average 80 per cent removal over a 30-day period. However, if a scrubbing system designed for 95 per cent SO_2 removal experiences a component failure which causes it to operate at 70 per cent removal for 10 hours, it will require that the scrubber be operated for 125 hours at 97 per cent SO_2 removal to achieve an average SO_2 removal of 95 per cent. Should multiple component failures occur in a 30-day period, then it may be impossible for the scrubber to achieve an average of 95 per cent SO_2 removal even if it could be operated at 100 per cent SO_2 removal.

The only way for a scrubber to achieve an average SO_2 removal rate of 95 per cent is to eliminate all avoidable outage time. This requires an extensive number of spare components. For the purposes of this analysis, extensive spare components have been included to attain maximum availability of the SO_2 removal equipment. Even with extensive spare components, outages caused by operator error or chemistry upsets which could affect overall unit availability cannot be eliminated.

To achieve 95 per cent SO_2 removal, an additional spray level will be required for each absorber module and an alkalinity enhancement addition will be used (i.e., adipic acid) to enhance liquid-to-gas mass transfer. In addition to the five absorber modules required to attain 95 per cent removal, four additional absorber modules will be utilized as follows. Based on the expected maintenance and inspection requirements, two (2) modules will be out of service undergoing inspection, preventive maintenance, or corrective maintenance. One module would be maintained in a stand-by status ready to go in service. The remaining module would be an "in service" reserve which would be needed to retain the 95 per cent overall system removal rate in the event one of the operating modules tripped or was forced out of service. Table 2-1 presents the additional capital and operating costs to upgrade the IPP scrubbers from 90 to 95 per cent SO_2 removal. The costs presented in Table 2-1 do not include the costs associated with delaying the project to redesign the scrubber system.

2.2 EFFECT OF UNAVOIDABLE SCRUBBER BREAKDOWNS ON COMPLIANCE WITH SO_2 EMISSION REGULATIONS

Unavoidable scrubber breakdowns may or may not apply to calculation of SO_2 removal efficiency on a 30-day rolling average. The EPA acknowledges[1] that it is inappropriate to impose a penalty for sudden and unavoidable malfunctions caused by circumstances beyond the control of the owner and/or operator. The term "malfunction" means that a large portion of or an entire SO_2 removal system is unavailable. Any malfunction which can be foreseen and avoided is not within the EPA's definition of a sudden and unavoidable malfunction.

System malfunctions resulting from auxiliary power failures, interruption of water supply, or natural phenomena such as earthquakes would probably quality under current EPA guidelines as an unavoidable malfunction. However, it is not clear from the current regulations exactly what constitutes an unavoidable malfunction. Most mechanical equipment failures can be avoided by using spare components. Therefore, are equipment breakdowns caused by scrubber coating failures, excessive corrosion, or system chemistry upsets avoidable or unavoidable? This analysis is based on the assumption that only breakdowns caused by natural phenomena or service system failure (i.e., loss of

[1]Bennett, Kathleen M., "Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions." EPA Memorandum, February 15, 1983.

TABLE 2-1. ADDITIONAL CAPITAL AND OPERATING COSTS TO UPGRADE THE IPP AIR QUALITY CONTROL SYSTEM FROM 90 TO 95 PER CENT SO_2 REMOVAL

Item	Unit 1 Capital Costs $1,000	Unit 2 Capital Costs $1,000
CAPITAL COSTS		
Raw Material Receiving and Storage	220	220
Additive Preparation	280	280
Flue Gas Desulfurization	15,400	15,400
Particulate Removal	--	--
Ash Handling	--	--
Flue Gas Reheaters	360	360
Ductwork	3,200	3,200
Waste Separation and Storage	380	380
Piping and Valves	1,680	1,680
Electrical	1,640	1,640
Controls and Instrumentation	1,840	1,840
Structures, Including Foundations and Support Steel	10,300	10,300
Total--Direct Costs (1983 dollars)	35,300	35,300
CAPITALIZED OPERATING COSTS		
Operating Personnel	2,700	2,600
Maintenance	31,900	30,800
Demand	34,400	34,400
Energy	6,700	6,500
Limestone Additive	600	600
Adipic Acid	7,600	7,300
Total Capitalized Operating Costs, $1986	83,900	82,200

auxiliary power or interruption of water supply) are unavoidable malfunctions. Should the appropriate regulatory agency provide a concise definition of what constitutes an unavoidable malfunction, a reduction in the amount of spare equipment may be possible.

2.3 EFFECT OF REDESIGNING SCRUBBER TO ACHIEVE 95 PER CENT SO_2 REMOVAL ON PROJECT SCHEDULE

The flue gas wet scrubber supplier, General Electric Environmental Services, Inc. (GEESI) stated in April 1983 that fabrication of the scrubber modules has been initiated. The current scrubber system under construction for the Intermountain Generating Station could not be retrofitted after start-up to continuously achieve a system removal efficiency of 95 per cent on a 30-day rolling average. GEESI indicated that a hold on fabrication and extensive reengineering of the wet scrubber system would be required to implement design changes. The engineering drawing schedule, after 2 to 4 months of contract renegotiations, is estimated to include the following.

Type of Document	Time of Submittal Days after contract award
1. Performance Curves and Design Data	
Performance Curves	60
Materials Balance Diagrams	60
Structural Design Data	120
Mechanical Design Data	90
Electrical Design Data	120
Control Design Data	300
2. Model Test Reports	
First Interim Report	When model fabrication is approximately 50 per cent complete.
Second Interim Report	When model flow testing is approximately 50 per cent complete.
Final Report	At the time of model flow demonstration at completion of model test.
3. Preliminary Drawings	
General arrangement and outline drawings required for plant layout. The drawings shall indicate locations	90

Type of Document	Time of Submittal Days after contract award
and dimensions of major equipment and ductwork, location and size of connections for Owner-furnished ductwork and piping, access requirements, clearance dimensions, thermal expansion movements, etc.	
Foundation and loading drawings, including load locations.	120
Drawings of all auxiliary equipment indicating all information required for supporting and piping the items. This shall include outline drawings of modules, tanks, pumps, mixers, blowers, etc., as well as all motors.	120
Drawings of all piping furnished as required to show routing, pipe supports, locations of valves, drains, instruments, accessories, and connections for Owner-furnished piping. Spool sheet and isometric assembly drawings shall be part of the submittal.	210
Drawings indicating details of ductwork, hoppers, expansion joints, supports, etc.	180
Insulation and lagging drawings	240
Auxiliary equipment drawings indicating electrical connections.	120
Elementary (schematic) diagrams and wiring diagrams.	240
Electrical one-line diagrams.	240
Arrangement drawings for electrical equipment and control devices.	240
Control logic and detailed control and instrument drawings.	300
Data sheets for all panel and field mounted instrumentation.	300
Cabinet and panel outline and layout drawings.	300

Type of Document	Time of Submittal Days after contract award
4. Certified Drawings	
General arrangement and outline drawings required for plant layout. The drawings shall indicate locations and dimensions of major equipment and ductwork, location and size of connections for Owner-furnished ductwork and piping, access requirements, clearance dimensions, thermal expansion movements, etc.	155
Foundation and loading drawings including load locations.	185
Drawings of all auxiliary equipment indicating all information required for supporting and piping the items. This shall include outline drawings of modules, tanks, pumps, mixers, blowers, etc., as well as all motors.	185
Drawings of all piping furnished as required to show routing, pipe supports, locations of valves, drains, instruments, accessories, and connections for Owner-furnished piping. Spool sheet and isometric assembly drawings shall be part of the submittal.	275
Drawings indicating details of ductwork, hoppers, expansion joints, supports, etc.	245
Insulation and lagging drawings.	305
Auxiliary equipment drawings indicating electrical connections.	185
Elementary (schematic) diagrams.	305
Electrical one-line diagram.	305
Arrangement drawings for electrical equipment and control devices.	305
Control logic and detailed control and instrument drawings.	365
Data sheets for all panel and field mounted instrumentation.	365
Cabinet and panel outline and layout drawings.	365

Construction of the wet scrubber could not be started until all of the drawings are certified. As presented in the schedule, this would be completed approximately 365 days after the contract is renegotiated with General Electric Environmental Services, Inc. Assuming that contract renegotiation requires 4 months, the total project delay as of April 1, 1983 would be approximately 16 months. This analysis is based on a June 1, 1983, decision to redesign the SO_2 removal system for 95 per cent SO_2 removal. The corresponding project delay would be approximately 18 months.

2.4 PROJECT COST IMPACTS

The project impact costs are a result of delaying the project by 18 months. The impact costs include costs for increased escalation, interest during construction, and costs for replacement power. Appendix A presents a discussion of the economic criteria used for the project. Appendix B presents a detailed sample calculation which illustrates the method used to evaluate cost impacts to the project.

Table 2-2 presents the project impact costs to upgrade the IPP scrubbers to achieve 95 per cent SO_2 removal. These costs include additional SO_2 removal equipment and capitalized operating costs as well as the additional interest, escalation, and replacement power. All cost impacts were discounted back to June 1, 1986 in order to be comparable with the original project costs. The June 1, 1986, present-worth cost of upgrading the IPP scrubbers to achieve 95 per cent SO_2 removal is estimated to be approximately 980 million dollars.

TABLE 2-2. CALCULATION OF NET CAPITAL COST IMPACT FOR 95 PER CENT SO_2 REMOVAL

	Unit 1 Capital Costs million $	Unit 2 Capital Costs million $	Units 1 & 2 Capital Costs million $
Capital Costs on As-Spent Basis	2089.0	1254.0	3343.0
Capital Cost Basis in 1983 Dollars	1930.0	1069.0	2999.0
Additional Capital Expenditure for 95% SO_2 Removal	35.3	35.3	70.6
Total Capital Investment	1965.3	1104.3	3069.6
Indirects (14 per cent)	375.1	154.6	429.7
Escalation to Midpoint of Construction @ 8.3% (all remaining cash flows)	275.6	308.6	584.2
Allowance for Funds Used during Construction @ 12%			
Funds already committed	266.1		266.1
Remaining funds	773.8	573.2	1347.0
Total Capital Costs Unit 1 - 1988$ Unit 2 - 1989$	3555.9	2140.8	5696.7
Present Worth of Total Capital Costs, 1986$	3000.0	1612.6	4612.6
Capitalized Value of Annual Operating Costs, 1986$	83.9	82.2	166.1
Replacement Power Costs due to Delay, 1986$	405.0	405.0	810.0
Total Cost of 95% SO_2 Removal, 1986 Dollars	3488.9	2099.8	5588.7
Present Worth of Total Capital Cost--Based on Original Project Estimate	3007.6	1600.9	4608.4
Differential Capital Costs Associated with Provisions for 95 per cent SO_2 Removal	481.3	498.9	980.3

3.0 ALTERNATIVE NO_x CONTROL METHODS

In this section, the following alternative means for controlling NO_x emissions are explored.

- Use of Selective Catalytic Reduction.
- Installation of Overfire Air Ports.
- Use of Flue Gas Recirculation.
- Lowering of Air Preheat Temperature.
- Use of Thermal DeNox Process (Exxon).
- Lowering the Excess Air Level to 5 to 6 per cent.
- Reducing Maximum Heat Input per Plan Area.

The capability of each alternative to provide potential improvements in NO_x emissions is discussed. In addition, the impact of the process upon unit capital costs, operating costs, project schedule, and unit performance are discussed. For applicable alternatives, the feasibility of installing the system one year after start-up as a retrofit application is also considered.

3.1 SELECTIVE CATALYTIC REDUCTION OF NO_x

Selective Catalytic Reduction (SCR) can remove 90 per cent of the NO_x from the incoming flue gas stream by chemically reducing NO_x with ammonia (NH_3) to form nitrogen and water. The reaction, which requires the injection of ammonia, takes place over catalyst beds at a temperature of approximately 250 C to 400 C (482 F to 725 F). In order to obtain these flue gas temperatures without reheat, the SCR is placed between the economizer section of the boiler and the air heater.

Operating the SCR at temperatures below 250 C (482 F) significantly increases the formation of ammonium bisulfate which is carried in the flue gas stream to the air heater. The ammonium bisulfate can severely corrode and plug the air heater. At temperatures above 400 C (752 F), thermal damage to the catalyst can result. A bypass around the SCR is necessary so that the generating unit operation is not curtailed when temperature restrictions cannot be met.

Catalysts grids used for SCR are generally based on vanadium or titanium dioxide compounds. Catalyst life is presently projected to be approximately two years, based on pilot plant testing completed on coal-fired units.

Ammonia for injection in the flue gas stream is stored onsite as a liquid. As the ammonia is required by the SCR system it is vaporized and diluted with combustion air drawn from the air heater outlet. This diluted ammonia vapor is then injected uniformly into the flue gas stream. The primary air fans size must be increased to supply the additional dilution air flow. The induced draft fans must also be increased in size to account for the additional pressure drop through the SCR System. Soot-blowers are installed in the SCR to maintain clean catalyst surfaces. To reduce ash erosion and pluggage of the reactive catalyst, a grid is installed upstream of the reactive catalyst.

Even though the majority of SCR equipment is located to the side of the generating units, the use of SCR would nevertheless require extensive boiler modification to provide passage of flue gas to and from the SCR unit. The system would draw boiler flue gas from just below the economizer and return flue gas to a point just ahead of the air heater.

B&W began detailed design of the boiler backend area, (i.e., economizer, economizer hopper, air heaters, etc.), about October 1981. If a decision to implement a SCR system were made on June 1, 1983, the project schedule would be set back to where it was in December 1981 as far as boiler design progress is concerned. The critical schedule path has no float for Unit 1 initial commercial operation date of July 1, 1986. Therefore, initial commercial operation of Unit 1 would be delayed by the interval of the set-back which is 18 months. Since craft labor availability in the project area will not support simultaneous construction of Units 1 and 2, Unit 2 would be similarly delayed. In a retrofit application, an outage of 6 months duration is anticipated.

Costs associated with this alternative are presented in Tables 3-1 through 3-4. Table 3-1 presents the summary of additional costs associated with initial installation of the SCR alternative. In Table 3-2, a breakdown of capital and operating costs are shown. Similar data are shown in Tables 3-3 and 3-4 for applying the SCR as a retrofit application. Cost data for remaining alternatives will be presented in the same fashion.

Costs for project delay include costs for increased escalation, interest

TABLE 3- 1. CALCULATION OF NET CAPITAL COST IMPACT
FOR SELECTIVE CATALYTIC REDUCTION

	UNIT 1 CAPITAL COSTS	UNIT 2 CAPITAL COSTS	UNITS 1 & 2 CAPITAL COSTS
	MILLION $	MILLION $	MILLION $
CAPITAL COSTS ON AS SPENT BASIS	2089.0	1254.0	3343.0
CAPITAL COST BASIS IN 1983 DOLLARS	1930.0	1069.0	2999.0
ADDITIONAL CAPITAL EXPENDITURE FOR THIS ALTERNATIVE	59.4	59.4	118.8
TOTAL CAPITAL INVESTMENT	1989.4	1128.4	3117.8
INDIRECTS (14 %)	278.5	158.0	436.5
ESCALATION TO MIDPOINT OF CONSTRUCTION @ 8.3 % (ALL REMAINING CASH FLOWS)	279.7	315.4	595.1
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION @ 12%			
FUNDS ALREADY COMMITTED	266.1		266.1
REMAINING FUNDS	785.4	585.7	1371.1
TOTAL CAPITAL COSTS UNIT 1 - 1988$ UNIT 2 - 1989$	3599.1	2187.5	5786.6
PRESENT WORTH OF TOTAL CAPITAL COSTS, 1986$	3036.5	1647.8	4684.3
CAPITALIZED VALUE OF ANNUAL OPERATING COSTS, 1986$	399.0	385.0	784.0
REPLACEMENT POWER COSTS DUE TO DELAY, 1986$	405.0	405.0	810.0
TOTAL COST OF ALTERNATIVE 1986 DOLLARS	3840.5	2437.8	6278.3
PRESENT WORTH OF TOTAL CAPITAL COST - BASED ON ORIGINAL BASIS	3007.6	1600.9	4608.4
DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR SELECTIVE CATALYTIC REDUCTION	832.9	836.9	1669.8

TABLE 3- 2. BREAKDOWN OF CAPITAL AND OPERATING COSTS-- SELECTIVE CATALYTIC REDUCTION

	Unit 1 Capital Costs	Unit 2 Capital Costs	Units 1 & 2 Capital Costs
	Million $	Million $	Million $
DIRECT CAPITAL COSTS (1983$)			
SCR EQUIPMENT	53.5	53.5	107.0
ELECTRICAL EQUIPMENT	3.6	3.6	7.2
INCREMENTAL ID FANS	2.3	2.3	4.6
TOTAL	59.4	59.4	118.8
CAPITALIZED ANNUAL COSTS OF OPERATION (1986 $)			
AIR COMPR. DEMAND & ENERGY	0.1	0.1	0.2
DRAFT FAN ENERGY	14.1	13.5	27.6
DRAFT FAN DEMAND	6.0	5.7	11.7
AMMONIA VAPORIZATION FUEL	4.7	4.3	9.0
AMMONIA	46.8	45.1	91.9
CATALYST	273.0	264.0	537.0
LABOR & SUPPLIES	54.3	52.3	106.6
TOTAL	399.0	385.0	784.0

TABLE 3- 3. CALCULATION OF NET CAPITAL COST IMPACT FOR SELECTIVE CATALYTIC REDUCTION - RETROFIT APPLICATION*

	UNIT 1 CAPITAL COSTS MILLION $	UNIT 2 CAPITAL COSTS MILLION $	UNITS 1 & 2 CAPITAL COSTS MILLION $
CAPITAL COSTS ON AS SPENT BASIS	2089.0	1254.0	3343.0
CAPITAL COST BASIS IN 1983 DOLLARS	1930.0	1069.0	2999.0
ADDITIONAL CAPITAL EXPENDITURE FOR THIS ALTERNATIVE	71.5	71.5	143.0
TOTAL CAPITAL INVESTMENT	2001.5	1140.5	3142.0
INDIRECTS (14 %)	280.2	159.7	439.9
ESCALATION:			
ESCALATION TO MIDPOINT OF CONSTRUCTION @ 8.3 % (ALL REMAINING CASH FLOWS OF ORIGINAL COST BASIS)	149.4	210.7	360.1
ESCALATION FOR RETROFIT OF SELECTIVE CATALYTIC REDUCTION MODIFICATIONS	17.8	26.0	43.8
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION @ 12%			
FUNDS ALREADY COMMITTED	162.0		162.0
REMAINING FUNDS	496.0	363.6	859.6
TOTAL CAPITAL COSTS UNIT 1 - 1986$ UNIT 2 - 1987$	3106.9	1900.5	5007.4
PRESENT WORTH OF TOTAL CAPITAL COSTS, 1986$	3106.9	1696.9	4803.8
CAPITALIZED VALUE OF ANNUAL OPERATING COSTS, 1986$	399.0	385.0	784.0
REPLACEMENT POWER COSTS DUE TO INSTALLATION OUTAGE	130.5	130.5	261.0
TOTAL COST OF ALTERNATIVE 1986 DOLLARS	3636.4	2212.4	5848.8
PRESENT WORTH OF TOTAL CAPITAL COST - BASED ON ORIGINAL BASIS	3007.6	1600.9	4608.4
DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH RETROFIT OF SELECTIVE CATALYTIC REDUCTION	628.8	611.5	1240.4

*Retrofit new SCR equipment 1 year after commercial operation.

TABLE 3-4. BREAKDOWN OF CAPITAL AND OPERATING COSTS--
SELECTIVE CATALYTIC REDUCTION - RETROFIT APPLICATION

	Unit 1 Capital Costs	Unit 2 Capital Costs	Units 1 & 2 Capital Costs
	Million $	Million $	Million $
DIRECT CAPITAL COSTS (1983$)			
SCR EQUIPMENT	65.6	65.6	131.2
ELECTRICAL EQUIPMENT	3.6	3.6	7.2
INCREMENTAL ID FANS	2.3	2.3	4.6
TOTAL	71.5	71.5	143.0
CAPITALIZED ANNUAL COSTS OF OPERATION (1986$)			
AIR COMPR. DEMAND & ENERGY	0.1	0.1	0.2
DRAFT FAN ENERGY	14.1	13.5	27.6
DRAFT FAN DEMAND	6.0	5.7	11.7
AMMONIA VAPORIZATION FUEL	4.7	4.3	9.0
AMMONIA	46.8	45.1	91.9
CATALYST	273.0	264.0	537.0
LABOR & SUPPLIES	54.3	52.3	106.6
TOTAL	399.0	385.0	784.0

during construction, and costs for replacement power. It is assumed that the center of gravity of the capital cost cash flows shifts by one-half of the delay for the respective unit when the SCR equipment is installed prior to commercial operation. It is assumed that, when retrofitted, the SCR equipment is installed one year after commercial operation. Further details of cost calculation methodology are presented in the sample calculation of Appendix B.

Costs for replacement power are based upon the differential fuel costs between coal and the replacement fuel - oil or gas. Other operating costs reflect differential operating costs which are incurred as a function of the process requirements.

3.2 OVERFIRE AIR PORTS

The installation of overfire air (OFA) ports effectively reduces the concentration of oxygen in the highest temperature regions of the furnace, thus impeding NO_x formation. With overfire air, NO_x emissions are predicted to be .45 lb/MBtu for specification bituminous coals, .10 lb/MBtu below emissions if no overfire air were used.

This alternative is probably the most feasible of the alternatives because it does not include advanced technology. Hence, balance-of-plant costs, i.e., costs for structural steel, platform, and HVAC rerouting, are less ($500,000 for Unit 1 and $200,000 for Unit 2). However, boiler system modifications impact many areas, including the following.

- 12 OFA port inserts.
- 48 revised burner openings and registers.
- Windbox.
- Ductwork.
- Extended lance wall blowers.
- Truss/buckstays.
- Wall attachments.
- Feeder ducts--foils/dampers.
- Platforms.
- Refractories, insulation, and lagging.
- Boiler ties.
- Controls.

To maintain required burner velocities for optimum flame shape/ stabilization, the 48 burner throats and burner registers would have to be reduced in size.

There are currently nine wall blowers in each of the front and rear walls which would have to have extended lances. Access to these blowers is currently off the top of the windbox. Platforms would have to be provided across the width of the unit.

Feeder ducts to the NO_x port plenum would be required, including dampers, damper drives, and air foils. Air foils would also have to be added to the existing windbox inlets at each row and on each end, for both front and rear walls.

A truss would be required at the top of the NO_x port plenum on both walls. These could impact the current boiler tie locations.

Carbon monoxide (CO) emissions are expected to increase when using overfire air. The predicted costs for additional fuel required to replace the heat lost by the increased CO emissions are listed in Table 3-5. Carbon levels in the fly ash are not expected to increase with overfire air operation.

From a schedule standpoint, it is more expeditious to add 12 OFA NO_x ports in the field rather than holding up panel fabrication. Nonetheless, if the OFA equipment is installed prior to commercial operation, the delay in the Unit 1 construction schedule is anticipated to be 14 months, extending the commercial operation date from July 1986 to September 1987. It is assumed that Unit 2, which is scheduled to begin commercial operation in July 1987, would be similarly delayed due to limitations in on-site construction personnel. If overfire air ports were to be retrofitted, the expected outage time for installation of the system is expected to be 6 months.

Costs for the installation of overfire air equipment are presented in Tables 3-5 through 3-8. As can be seen in Tables 3-5 and 3-7, the predicted costs for this alternative are 569 million 1986 dollars and 277 million 1986 dollars for a new and retrofit application, respectively.

3.3 FLUE GAS RECIRCULATION

In this alternative, approximately 15 per cent of the flue gas flow is diverted at the economizer hopper and recirculated back to the hot secondary

TABLE 3- 5. CALCULATION OF NET CAPITAL COST IMPACT FOR OVERFIRE AIR PORTS

	UNIT 1 CAPITAL COSTS	UNIT 2 CAPITAL COSTS	UNITS 1 & 2 CAPITAL COSTS
	MILLION $	MILLION $	MILLION $
CAPITAL COSTS ON AS SPENT BASIS	2089.0	1254.0	3343.0
CAPITAL COST BASIS IN 1983 DOLLARS	1930.0	1069.0	2999.0
ADDITIONAL CAPITAL EXPENDITURE FOR THIS ALTERNATIVE	6.9	3.4	10.3
TOTAL CAPITAL INVESTMENT	1936.9	1072.4	3009.3
INDIRECTS (14 %)	271.2	150.1	421.3
ESCALATION TO MIDPOINT OF CONSTRUCTION @ 8.3 % (ALL REMAINING CASH FLOWS)	243.3	279.6	522.9
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION @ 12%			
FUNDS ALREADY COMMITTED	241.4		241.4
REMAINING FUNDS	697.7	510.9	1208.7
TOTAL CAPITAL COSTS UNIT 1 - 1987$ UNIT 2 - 1988$	3390.5	2013.1	5403.6
PRESENT WORTH OF TOTAL CAPITAL COSTS, 1986$	2970.6	1574.8	4545.4
CAPITALIZED VALUE OF ANNUAL OPERATING COSTS, 1986$	1.1	1.1	2.2
REPLACEMENT POWER COSTS DUE TO DELAY, 1986$	315.0	315.0	630.0
TOTAL COST OF ALTERNATIVE 1986 DOLLARS	3286.7	1890.9	5177.6
PRESENT WORTH OF TOTAL CAPITAL COST - BASED ON ORIGINAL BASIS	3007.6	1600.9	4608.4
DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR OVERFIRE AIR PORTS	279.1	290.0	569.1

TABLE 3- 6. BREAKDOWN OF CAPITAL AND OPERATING COSTS--
OVERFIRE AIR PORTS

	Unit 1 Capital Costs	Unit 2 Capital Costs	Units 1 & 2 Capital Costs
	Million $	Million $	Million $
DIRECT CAPITAL COSTS (1983$)			
BOILER SYSTEMS	6.4	3.2	9.6
BALANCE OF PLANT	0.5	0.2	0.7
TOTAL	6.9	3.4	10.3
CAPITALIZED ANNUAL COSTS OF OPERATION			
UNBURNED COMBUSTIBLES	1.1	1.1	2.2
TOTAL	1.1	1.1	2.2

TABLE 3- 7. CALCULATION OF NET CAPITAL COST IMPACT FOR OVERFIRE AIR PORTS - RETROFIT APPLICATION *

	UNIT 1 CAPITAL COSTS MILLION $	UNIT 2 CAPITAL COSTS MILLION $	UNITS 1 & 2 CAPITAL COSTS MILLION $
CAPITAL COSTS ON AS SPENT BASIS	2089.0	1254.0	3343.0
CAPITAL COST BASIS IN 1983 DOLLARS	1930.0	1069.0	2999.0
ADDITIONAL CAPITAL EXPENDITURE FOR THIS ALTERNATIVE	6.9	3.4	10.3
TOTAL CAPITAL INVESTMENT	1936.9	1072.4	3009.3
INDIRECTS (14 %)	271.2	150.1	421.3
ESCALATION:			
ESCALATION TO MIDPOINT OF CONSTRUCTION @ 8.3 % (ALL REMAINING CASH FLOWS OF ORIGINAL COST BASIS)	149.4	210.7	360.1
ESCALATION FOR RETROFIT OF OVERFIRE AIR PORTS MODIFICATIONS	1.7	1.2	2.9
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION @ 12%			
FUNDS ALREADY COMMITTED	162.0		162.0
REMAINING FUNDS	496.0	363.6	859.6
TOTAL CAPITAL COSTS UNIT 1 - 1986$ UNIT 2 - 1987$	3017.2	1798.0	4815.2
PRESENT WORTH OF TOTAL CAPITAL COSTS, 1986$	3017.2	1605.4	4622.6
CAPITALIZED VALUE OF ANNUAL OPERATING COSTS, 1986$	1.1	1.1	2.2
REPLACEMENT POWER COSTS DUE TO INSTALLATION OUTAGE	130.5	130.5	
TOTAL COST OF ALTERNATIVE 1986 DOLLARS	3148.8	1737.0	4885.8
PRESENT WORTH OF TOTAL CAPITAL COST - BASED ON ORIGINAL BASIS	3007.6	1600.9	4608.4
DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH RETROFIT OF OVERFIRE AIR PORTS	141.2	136.1	277.4

*New OFA equipment retrofitted one year after commercial operation.

TABLE 3- 8. BREAKDOWN OF CAPITAL AND OPERATING COSTS--
OVERFIRE AIR PORTS - RETROFIT APPLICATION

	Unit 1 Capital Costs	Unit 2 Capital Costs	Units 1 & 2 Capital Costs
	Million $	Million $	Million $
DIRECT CAPITAL COSTS (1983$)			
BOILER SYSTEMS	6.4	3.2	9.6
BALANCE OF PLANT	0.5	0.2	0.7
TOTAL	6.9	3.4	10.3
CAPITALIZED ANNUAL COSTS OF OPERATION			
UNBURNED COMBUSTIBLES	1.1	1.1	2.2
TOTAL	1.1	1.1	2.2

air system at the air foils, after passing through a mechanical dust collector and flue gas recirculation (FGR) fans. It is predicted that NO_x emissions are reduced to 0.47 lb/MBtu for the specification bituminous coals. Costs for this alternative are summarized in Tables 3-9 and 3-10.

Boiler system changes are anticipated in the following areas.

- Two gas recirculation fans, motors, turning gears and dust collectors.
- Economizer hopper.
- Ductwork.
- Entire convection surface reengineering (because of the increased gas mass velocity). Bank depths, arrangements, and tube metals may change, potentially affecting top support loads and locations.
- Refractory, insulation, and lagging.
- Boiler ties.
- Controls.

Because of the lack of design provisions for this alternative, balance-of-plant modifications are extensive. The new ductwork would interfere with the major load-bearing structures in the boiler building, involving a redesign of the structural steel if feasible. Heating and ventilating ductwork and piping would be rerouted, some equipment would have to be moved, and miscellaneous mechanical and electrical equipment would be required. Balance-of-plant impacts should be reduced for Unit 2. As seen in Table 3-9, the 1983 capital costs for the modifications to Units 1 and 2 are $23.8 million.

Predicted capitalized costs of operation are shown in Table 3-10. Energy and demand costs are associated with the new power requirements of the FGR fans and increased power requirements of the induced draft (ID) fans. Increased ID fan power is required to overcome the increased head loss in the convective passes because of the 15 per cent flow increase due to flue gas recirculation.

Flue gas recirculation fans have been notably unreliable. Many existing units have had their recirculating fans and systems removed. Ten-year average NERC data indicate approximately 7 hours of downtime per unit-year attributable to recirculating fans. This downtime appears too low, possibly

TABLE 3- 9. CALCULATION OF NET CAPITAL COST IMPACT FOR FLUE GAS RECIRCULATION

	UNIT 1 CAPITAL COSTS	UNIT 2 CAPITAL COSTS	UNITS 1 & 2 CAPITAL COSTS
	MILLION $	MILLION $	MILLION $
CAPITAL COSTS ON AS SPENT BASIS	2089.0	1254.0	3343.0
CAPITAL COST BASIS IN 1983 DOLLARS	1930.0	1069.0	2999.0
ADDITIONAL CAPITAL EXPENDITURE FOR THIS ALTERNATIVE	13.1	10.7	23.8
TOTAL CAPITAL INVESTMENT	1943.1	1079.7	3022.8
INDIRECTS (14 %)	272.0	151.2	423.2
ESCALATION TO MIDPOINT OF CONSTRUCTION @ 8.3 % (ALL REMAINING CASH FLOWS)	313.8	332.6	646.4
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION @ 12%			
FUNDS ALREADY COMMITTED	304.9		304.9
REMAINING FUNDS	862.1	633.1	1495.2
TOTAL CAPITAL COSTS UNIT 1 - 1988$ UNIT 2 - 1989$	3696.0	2196.6	5892.5
PRESENT WORTH OF TOTAL CAPITAL COSTS, 1986$	2946.4	1563.5	4509.9
CAPITALIZED VALUE OF ANNUAL OPERATING COSTS, 1986$	8.9	8.9	17.8
CAPITALIZED VALUE OF ANNUAL REPLACEMENT COSTS, 1986$	5.7	5.7	11.4
REPLACEMENT POWER COSTS DUE TO DELAY, 1986$	540.0	540.0	1080.0
TOTAL COST OF ALTERNATIVE 1986 DOLLARS	3501.0	2118.1	5619.1
PRESENT WORTH OF TOTAL CAPITAL COST - BASED ON ORIGINAL BASIS	3007.6	1600.9	4608.4
DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR FLUE GAS RECIRCULATION	493.4	517.2	1010.6

TABLE 3-10. BREAKDOWN OF CAPITAL AND OPERATING COSTS--
FLUE GAS RECIRCULATION

	Unit 1 Capital Costs	Unit 2 Capital Costs	Units 1 & 2 Capital Costs
	Million $	Million $	Million $
DIRECT CAPITAL COSTS (1983$)			
BOILER SYSTEMS	8.3	8.3	16.6
BALANCE OF PLANT	4.8	2.4	7.2
TOTAL	13.1	10.7	23.8
CAPITALIZED ANNUAL COSTS OF OPERATION			
FGR FAN ENERGY	5.9	5.9	11.8
FGR FAN DEMAND	1.2	1.2	2.4
ID FAN ENERGY	1.5	1.5	3.0
ID FAN DEMAND	0.3	0.3	0.6
TOTAL	8.9	8.9	17.8
CAPITALIZED REPLACEMENT POWER COSTS OF OPERATION			
FGR FAN FAILURE	2.2	2.2	4.4
CONVECTIVE PASS DESIGN	3.5	3.5	7.0
TOTAL	5.7	5.7	11.4

because it may have been normalized with data from units without recirculating fans and operation of existing units is typically intermittent for steam temperature control. Replacement power costs for recirculating fan downtime are listed in Table 3-10 based on 7 hours of outage time per recirculating fan per year.

Because of the increased convection pass gas flow, erosion of convection pass tubes should increase. Replacement power costs in Table 3-10 are based on a full forced outage rate of 10 hours per year--about 5 per cent of the 10-year average NERC downtime associated with superheater, reheater, and economizer tube failures.

The Unit 1 delay for initial FGR implementation is estimated to be 2 years, extending the Unit 1 commercial operation date from July 1986 to July 1988. Unit 2, scheduled for a July 1987 start-up, is also assumed to be delayed two years to July 1989 also. Impact costs in Table 3-9 due to the project delay are calculated in the manner described previously.

As seen in Table 3-9, the total additional capitalized costs are predicted to be $1,010,600,000 (1986 $) for an NO_x reduction of 0.08 lb/MBtu.

3.4 REDUCED COMBUSTION AIR TEMPERATURE

A paper by the Southern California Edison Company and Dynamic Science, published in the 1970 proceedings of the American Power Conference, indicated that a combustion air temperature decrease of 650 F to 580 F resulted in a 20 per cent NO_x reduction in a gas fired unit. The gas fired unit utilized turbulent circular burners with no other NO_x control methods.

The coal fired boilers for the Intermountain Power Project are equipped with dual register burners. Since a degree of NO_x control (by staged combustion) is already present, Babcock & Wilcox (B&W) feels that a similar reduction in combustion air temperature will have a negligible impact on NO_x emission levels.

B&W's minimum recommended air temperature for coal firing is 500 F at full load, noting that poor flame stability, increased stack opacity, and increased use of oil during start-up could result. At maximum continuous rating (MCR), secondary air temperatures are 645 F and primary air temperatures are 420 F at the mills. Therefore, only a moderate reduction in combustion zone temperature is possible. It is assumed, for comparison purposes only, that the NO_x reduction with reduced combustion air temperatures will be by no more than 20 per cent and, most probably, nearer 0 per cent. Hence, for bituminous coals with 500 F combustion air, NO_x emissions are assumed to be greater than 0.45 lb/MBtu, probably nearer 0.55 lb/MBtu.

Boiler system modifications are negligible--merely removing air heater surface. However, the reduced heat transfer in the air heaters will result in a boiler efficiency penalty of approximately 3 per cent* and increased air heater outlet flue gas temperatures (from 280 F to approximately 390 F). The decreased boiler efficiency requires an increased fuel burn rate at all load points. Hence, fuel-related system (e.g., fuel handling, crushers, mills, etc.) energy and demand costs increase. Additionally, the increased flue gas flow rate (because of the reduced boiler efficiency) and increased air heater outlet flue gas temperature significantly affect air quality control equipment and induced draft fan design and performance.

Capital costs listed in Table 3-11 are incremental costs only for air quality control system (AQCS) and ID fan upgrading. The incremental capital costs are not for modifications to contracted equipment but, rather, the difference in cost between new larger equipment and new equipment as currently specified. Therefore, capital costs in Table 3-11 should be considered low.

Capitalized operating costs in Table 3-12, other than increased fuel costs, are on the same basis as the above capital costs, i.e., only those costs associated with upgrading the AQCS and ID fans are included. There are other costs (e.g., costs for increased unburned combustibles, energy and demand costs for coal handling equipment, etc.) which have not been calculated. Hence, operating costs in Table 3-11 should be considered low.

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*It is assumed the steam side of the system cannot be redesigned to maintain efficiency.

TABLE 3-11. CALCULATION OF NET CAPITAL COST IMPACT FOR REDUCED COMBUSTION AIR TEMP.

	UNIT 1 CAPITAL COSTS MILLION $	UNIT 2 CAPITAL COSTS MILLION $	UNITS 1 & 2 CAPITAL COSTS MILLION $
CAPITAL COSTS ON AS SPENT BASIS	2089.0	1254.0	3343.0
CAPITAL COST BASIS IN 1983 DOLLARS	1930.0	1069.0	2999.0
ADDITIONAL CAPITAL EXPENDITURE FOR THIS ALTERNATIVE	15.0	15.0	30.0
TOTAL CAPITAL INVESTMENT	1945.0	1084.0	3029.0
INDIRECTS (14 %)	272.3	151.8	424.1
ESCALATION TO MIDPOINT OF CONSTRUCTION @ 8.3 % (ALL REMAINING CASH FLOWS)	272.1	303.0	575.1
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION @ 12%			
FUNDS ALREADY COMMITTED	266.1		266.1
REMAINING FUNDS	764.1	562.7	1326.7
TOTAL CAPITAL COSTS UNIT 1 - 1988$ UNIT 2 - 1989$	3519.6	2101.4	5621.0
PRESENT WORTH OF TOTAL CAPITAL COSTS, 1986$	2969.4	1582.9	4552.3
CAPITALIZED VALUE OF ANNUAL OPERATING COSTS, 1986$	64.5	64.5	129.0
REPLACEMENT POWER COSTS DUE TO DELAY, 1986$	405.0	405.0	810.0
TOTAL COST OF ALTERNATIVE 1986 DOLLARS	3438.9	2052.4	5491.3
PRESENT WORTH OF TOTAL CAPITAL COST - BASED ON ORIGINAL BASIS	3007.6	1600.9	4608.4
DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR REDUCED COMBUSTION AIR TEMP.	431.3	451.6	882.9

TABLE 3-12. BREAKDOWN OF CAPITAL AND OPERATING COSTS--
REDUCED COMBUSTION AIR TEMP.

	Unit 1 Capital Costs	Unit 2 Capital Costs	Units 1 & 2 Capital Costs
	Million $	Million $	Million $
DIRECT CAPITAL COSTS (1983$)			
INCREMENTAL FGD EQUIP.	15.0	15.0	30.0
TOTAL	15.0	15.0	30.0
CAPITALIZED ANNUAL COSTS OF OPERATION			
ADDITIONAL FUEL COSTS	51.0	51.0	102.0
AQCS ENERGY	8.2	8.2	16.4
AQCS DEMAND	1.5	1.5	3.0
OTHER AQCS O & M	3.8	3.8	7.6
TOTAL	64.5	64.5	129.0

The estimated Unit 1 delay for initial implementation of this alternative is 18 months, delaying commercial operation from July 1986 to January 1988. Unit 2, scheduled to start-up in July 1987, is assumed to be equally delayed. Impact costs associated with the 18-month delay of Unit 1 and Unit 2 are listed in Table 3-11.

The total additional capitalized costs when combustion air temperatures are reduced to 500 F is estimated to be at least $883 million (1986 $) for, at most, a reduction in NO_x emissions of 0.10 lb/MBtu.

3.5 THERMAL $DENO_x$

Exxon Research and Engineering Company has recently patented a process for removal of NO_x from flue gas streams by the injection of ammonia into the hot flue gas within the boiler enclosure. The success of the system is dependent upon the following factors.

- Proper mixing of the ammonia with the flue gas. Exxon uses a number of sonic nozzles to propel an ammonia/air or ammonia/steam mixture into the flue gas.
- Proper flue gas temperature. The ability of the process is quite temperature dependent. Flue gas temperatures must be approximately 1800 F in order for the process to function satisfactorily. In fact, a variance from the specified temperature may not only render the process ineffective, but actually increase the NO_x emissions. Therefore, Exxon must select a number of injection points to properly handle unit partial load operation. (Flue gas temperatures drop throughout the furnace as the load decreases.)

Exxon believes that, for a unit of this size, a 20 per cent reduction is possible without significant impact on the downstream equipment. Removal efficiencies of up to 50 per cent may be within the capabilities of the process but are coupled with potential problems, particularly in the areas of air heater corrosion and pluggage. Due to additional penalties in unit availability (for removal efficiencies greater than 20 per cent), the expected capability of this process is to reduce NO_x emissions 20 per cent, or from 0.55 pounds/MBtu to 0.44 pounds/MBtu.

However, potential operation of a $DeNO_x$ system--even at the 20 per cent design point--has several possible drawbacks as tabulated below.

- The $DeNO_x$ technology is quite new and has not been tested in a full scale coal fired boiler application. Actual unit experience is limited to oil and gas fired boilers. In these units, ash fouling and corrosion problems are not a major concern and, therefore, these units exhibit a smaller furnace cross-sectional area and a different surface arrangement. Long term effects of potential additional corrosion (especially in the regions of the injection nozzles) due to the presence of ammonia are not known.

- The presence of ammonia within the flue gas may also alter the fouling characteristics of the fuel. Additional soot blowing requirements or unit unavailability may result. Again, without full scale long term testing, these impacts cannot be determined.
- Present operating experience to date has focused on much smaller boilers. The ability of the proposed nozzle arrangement to properly mix the ammonia throughout the flue gas is also unknown.
- Performance guarantees as to unit NO_x emissions and unit availability from Babcock & Wilcox would not be offered in the event the $DeNO_x$ process was used. It is their opinion that use of such a system might result in operating problems beyond their direct control.
- The operating costs of the system, both in terms of ammonia consumption and in terms of auxiliary power requirements, must be considered. The expected capitalized operating cost for the system in June 1986 dollars is expected to be $18.4 million for 20 per cent NO_x removal ($45 million for 50 per cent removal).

Installation of the system, in terms of space limitations, appears to be feasible as the majority of equipment (tanks, compressors, etc.) can be located at a convenient location on the plant site and not near the boiler. Distribution of the ammonia stream would be carried out by a series of pipes (less than 6-inch O.D.) running beside the boiler sidewalls. The construction period should not exceed 3 to 4 months, and no delay in the project start-up date is predicted. If the system were to be retrofitted, the outage period required should not exceed 1 to 2 weeks.

Projected capital and capitalized operating costs for the $DeNO_x$ system are shown in Tables 3-13 and 3-14 for a new plant application and in Tables 3-15 and 3-16 for a retrofit application. The present worth in June 1986 dollars for these two alternatives is 216.5 million dollars and 81.5 million dollars, respectively. These costs do not reflect any potential costs associated with additional unit unavailability or maintenance and could be subject to significant increases which cannot be projected based upon current information.

TABLE 3-13. CALCULATION OF NET CAPITAL COST IMPACT FOR THERMAL DENOX (20% REDUCTION)

	UNIT 1 CAPITAL COSTS	UNIT 2 CAPITAL COSTS	UNITS 1 & 2 CAPITAL COSTS
	MILLION $	MILLION $	MILLION $
CAPITAL COSTS ON AS SPENT BASIS	2089.0	1254.0	3343.0
CAPITAL COST BASIS IN 1983 DOLLARS	1930.0	1069.0	2999.0
ADDITIONAL CAPITAL EXPENDITURE FOR THIS ALTERNATIVE	6.6	6.6	13.3
TOTAL CAPITAL INVESTMENT	1936.6	1075.6	3012.3
INDIRECTS (14 %)	271.1	150.6	421.7
ESCALATION TO MIDPOINT OF CONSTRUCTION @ 8.3 % (ALL REMAINING CASH FLOWS)	176.2	231.2	407.5
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION @ 12%			
FUNDS ALREADY COMMITTED	183.6		183.6
REMAINING FUNDS	552.2	405.6	957.8
TOTAL CAPITAL COSTS UNIT 1 - 1986$ UNIT 2 - 1987$	3119.8	1863.1	4982.9
PRESENT WORTH OF TOTAL CAPITAL COSTS, 1986$	3004.1	1601.8	4605.9
CAPITALIZED VALUE OF ANNUAL OPERATING COSTS, 1986$	19.5	19.5	39.0
REPLACEMENT POWER COSTS DUE TO DELAY, 1986$	90.0	90.0	180.0
TOTAL COST OF ALTERNATIVE 1986 DOLLARS	3113.6	1711.3	4824.9
PRESENT WORTH OF TOTAL CAPITAL COST - BASED ON ORIGINAL BASIS	3007.6	1600.9	4608.4
DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR THERMAL DENOX (20% REDUCTION)	106.1	110.4	216.5

TABLE 3-14. BREAKDOWN OF CAPITAL AND OPERATING COSTS--
THERMAL DENOX (20% REDUCTION)

	Unit 1 Capital Costs	Unit 2 Capital Costs	Units 1 & 2 Capital Costs
	Million $	Million $	Million $
DIRECT CAPITAL COSTS (1983$)			
THERMAL DENOX EQUIPMENT	4.5	4.5	9.1
LISCENSING	2.1	2.1	4.2
TOTAL	6.6	6.6	13.3
CAPITALIZED ANNUAL COSTS OF OPERATION			
AMMONIA	12.0	12.0	24.0
DEMAND	1.1	1.1	2.3
ENERGY	6.2	6.2	12.3
STEAM	0.2	0.2	0.4
TOTAL	19.5	19.5	39.0

TABLE 3-15. CALCULATION OF NET CAPITAL COST IMPACT FOR THERMAL DENOX (20% REDUCTION) - RETROFIT APPLICATION*

	UNIT 1 CAPITAL COSTS	UNIT 2 CAPITAL COSTS	UNITS 1 & 2 CAPITAL COSTS
	MILLION $	MILLION $	MILLION $
CAPITAL COSTS ON AS SPENT BASIS	2089.0	1254.0	3343.0
CAPITAL COST BASIS IN 1983 DOLLARS	1930.0	1069.0	2999.0
ADDITIONAL CAPITAL EXPENDITURE FOR THIS ALTERNATIVE	7.5	7.5	15.1
TOTAL CAPITAL INVESTMENT	1937.5	1076.5	3014.0
INDIRECTS (14 %)	271.3	150.7	422.0
ESCALATION:			
ESCALATION TO MIDPOINT OF CONSTRUCTION @ 8.3 % (ALL REMAINING CASH FLOWS OF ORIGINAL COST BASIS)	149.4	210.7	360.1
ESCALATION FOR RETROFIT OF THERMAL DENOX (20% REDUCTION) MODIFICATIONS	1.9	2.8	4.7
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION @ 12%			
FUNDS ALREADY COMMITTED	162.0		162.0
REMAINING FUNDS	496.0	363.6	859.6
TOTAL CAPITAL COSTS UNIT 1 - 1986$ UNIT 2 - 1987$	3018.1	1804.3	4822.4
PRESENT WORTH OF TOTAL CAPITAL COSTS, 1986$	3018.1	1611.0	4629.1
CAPITALIZED VALUE OF ANNUAL OPERATING COSTS, 1986$	19.5	19.5	39.0
REPLACEMENT POWER COSTS DUE TO INSTALLATION OUTAGE	10.9	10.9	21.8
TOTAL COST OF ALTERNATIVE 1986 DOLLARS	3048.5	1641.4	4689.9
PRESENT WORTH OF TOTAL CAPITAL COST - BASED ON ORIGINAL BASIS	3007.6	1600.9	4608.4
DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH RETROFIT OF THERMAL DENOX (20% REDUCTION)	40.9	40.5	81.5

*Retrofit new thermal $DeNO_x$ equipment 1 year after commercial operation.

TABLE 3-16. BREAKDOWN OF CAPITAL AND OPERATING COSTS--
THERMAL DENOX (20% REDUCTION) - RETROFIT APPLICATION

	Unit 1 Capital Costs	Unit 2 Capital Costs	Units 1 & 2 Capital Costs
	Million $	Million $	Million $
DIRECT CAPITAL COSTS (1983$)			
THERMAL DENOX EQUIPMENT	5.4	5.4	10.9
LISCENSING	2.1	2.1	4.2
TOTAL	7.5	7.5	15.1
CAPITALIZED ANNUAL COSTS OF OPERATION			
AMMONIA	12.0	12.0	24.0
DEMAND	1.1	1.1	2.3
ENERGY	6.2	6.2	12.3
STEAM	0.2	0.2	0.4
TOTAL	19.5	19.5	39.0

3.6 OPERATION OF UNIT USING 5 TO 6 PER CENT EXCESS AIR

In oil and gas fired boilers, it has been found that NO_x can be significantly reduced by adjusting the excess air level to 5 to 6 per cent. Due to the nature of these fuels (highly volatile, good flame stability, etc.), these levels of excess air are adequate to properly support combustion. When burning coal, the availability of oxygen within the combustion zone is essential to proper and complete combustion. At the 5 to 6 per cent excess air level, while some fuel will have sufficient and even excessive oxygen available for complete combustion (oxidizing atmosphere), the remaining fuel will not have the necessary oxygen in close proximity and will not fully combust (reducing atmosphere). The presence of unburned fuel within the flue gas poses the following problems.

- Excessive fuel requirements. The boiler efficiency will drop significantly due to the incomplete combustion. Additional fuel must be burned in order to meet heat input requirements.
- Possible furnace explosion. Incomplete combustion may result in an accumulation of unburned fuel within the furnace. If such a deposit should suddenly come in contact with a sufficient quantity of air, a furnace explosion can result.
- Possible slagging problems. Chemical compounds which are created in an oxidizing atmosphere (during complete combustion) differ from those which are created in a reducing atmosphere. Compounds formed in a reducing atmosphere tend to display lower melting temperatures and may, therefore, cause additional wall deposits to form in the furnace zone. In addition, lack of sufficient excess air may alter the shape of the fireball (longer and higher within the furnace) and cause excessive gas temperatures within the upper furnace. Higher gas temperatures may lead to further formation of slagging deposits and alter the heat balance such that proper steam conditions are difficult to meet.
- Possible corrosion problems. Due to the presence of the reducing atmosphere (and the resulting ash composition), excessive corrosion may occur on high temperature surfaces.

While viable for a gas or oil fired unit, the use of low excess air levels as a means of controlling NO_x is considered to be unsatisfactory for the IPP coal fired boilers.

3.7 LOWERING MAXIMUM PLAN HEAT RELEASE RATE

Under this alternative, the maximum plan heat release rate (MBtu/hr-ft^2) at which the boiler can operate would be lowered. The boiler plan (cross-sectional) area can be altered only by total redesign of the boiler and surrounding structures and would result in excessive project delay and expense. However, the heat release rate can be lowered by decreasing the heat input and, thus, maximum load capability.

While the quantity of NO_x generated does, in fact, decrease as load is reduced, the impact is predicted to be minimal. According to B&W, for unit operation at 75 per cent load, the NO_x output is predicted to be 0.48 lb/MBtu as compared to 0.55 lb/MBtu for operation at 100 per cent load. A curve depicting the expected NO_x emissions as a function of load is presented on Figure 3-1. Expected NO_x emissions as a function of heat input per plan area are tabulated below.

Load per cent	Heat Input per Plan Area MBtu/hr-ft^2	Expected NO_x Emissions lb/MBtu
MCR	1.60	0.58
100	1.48	0.55 (guarantee)
75	1.10	0.48

Costs associated with this alternative are calculated by determining the total number of megawatt-hours of power which must be replaced by other sources based upon the projected load curve. For example, the capitalized operating cost for limiting the heat input per plan area to 1.1 MBtu/hr-ft^2 is $465 million June 1986 dollars for a reduction in NO_x emissions of 0.07 lb/MBtu. Costs for this alternative are presented in Table 3-17.

3.8 ROLE OF FUEL-BOUND NITROGEN IN NO_x EMISSION LEVEL

Research conducted for oil and gas fired units have indicated that the level of NO_x emitted from the furnace can be correlated to the fuel-bound nitrogen level. However, according to Babcock & Wilcox, for coal fired units, the level of NO_x leaving the furnace has not been correlated to the

TABLE 3-17. CALCULATION OF NET CAPITAL COST IMPACT FOR LOWERING MAX. HEAT INPUT

	UNIT 1 CAPITAL COSTS	UNIT 2 CAPITAL COSTS	UNITS 1 & 2 CAPITAL COSTS
	MILLION $	MILLION $	MILLION $
CAPITAL COSTS ON AS SPENT BASIS	2089.0	1254.0	3343.0
CAPITAL COST BASIS IN 1983 DOLLARS	1930.0	1069.0	2999.0
ADDITIONAL CAPITAL EXPENDITURE FOR THIS ALTERNATIVE	0.0	0.0	0.0
TOTAL CAPITAL INVESTMENT	1930.0	1069.0	2999.0
INDIRECTS (14 %)	270.2	149.7	419.9
ESCALATION TO MIDPOINT OF CONSTRUCTION @ 8.3 % (ALL REMAINING CASH FLOWS)	149.4	210.7	360.1
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION @ 12%			
FUNDS ALREADY COMMITTED	162.0		162.0
REMAINING FUNDS	496.0	363.6	859.6
TOTAL CAPITAL COSTS UNIT 1 - 1986$ UNIT 2 - 1987$	3007.6	1793.0	4800.6
PRESENT WORTH OF TOTAL CAPITAL COSTS, 1986$	3007.6	1600.9	4608.4
CAPITALIZED VALUE OF ANNUAL REPLACEMENT COSTS, 1986$	465.0	465.0	930.0
TOTAL COST OF ALTERNATIVE 1986 DOLLARS	3472.6	2065.9	5538.4
PRESENT WORTH OF TOTAL CAPITAL COST - BASED ON ORIGINAL BASIS	3007.6	1600.9	4608.4
DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR LOWERING MAX. HEAT INPUT	465.0	465.0	930.0

nitrogen content of the fuel successfully. In essence, the larger quantity of excess air required for coal combustion masks the impact of fuel nitrogen contribution. Thus, while a lower nitrogen content for a chosen fuel is desirable, quantifying the impact of fuel-bound nitrogen in NO_x emissions is not currently possible.

APPENDIX A
CRITERIA FOR ECONOMIC EVALUATION

The Intermountain Generating Station, Units 1 and 2, is being developed by the Intermountain Power Agency. The cities of Anaheim, Burbank, Glendale, Los Angeles, Pasadena, and Riverside in southern California, Utah Power and Light, and Intermountain Consumers Power Association (ICPA) have contracted to purchase the power produced by the station. The following economic criteria is used in this study.

Evaluation Period

The evaluation period for each unit will be 35 years.

Unit	Evaluation Period
1	July 1, 1986 to June 30, 2021
2	July 1, 1987 to June 30, 2022

1. Present Worth Discount Rate and Present Worth Factors.

The present worth concept is a method of taking into account the time value of money. Using an interest rate, also called the present worth discount rate, present worth factors are developed which can be used to convert future expenditures to an equivalent single value at one point in time.

For investor-owned utilities, the present worth discount rate is considered to be their weighted average cost of capital, considering both the cost of debt capital (bonds) and the cost of equity capital (preferred stock, common stock, retained earnings). For publicly owned utilities, which usually have 100 per cent bond financing, the present worth discount rate is considered to be equal to the estimated bond interest rate.

The factors most commonly used in present worth arithmetic are the Single Payment Present Worth Factor, the Uniform Series Present Worth Factor, and the Capital Recovery Factor, as shown in the following tabulation and discussed in the following paragraphs.

Factor	Abbrev.	Functional Symbol	Forumual Used to Calculate Factor
Single Payment Present Worth Factor	PWF	P/F, i, n	$\frac{1}{(1+i)^n}$
Uniform Series Present Worth Factor	USPWF	P/A, i, N	$\sum_{1}^{n} PWF$, or $\frac{1-\frac{1}{(1+i)^n}}{i}$
Capital Recovery Factor	CRF	A/P, i, n	$\frac{1}{USPWF}$, or $\frac{i}{1-\frac{1}{(1+i)^n}}$

The functional symbols are those used in the textbook Principles of Engineering Economy by Grant, Ireson, and Leavenworth. They are based on the following.

- i--Interest rate per period.
- n--Number of interest periods.
- P--Present sum of money.
- F--Future sum of money equivalent to P.
- A--End-of-year payment in a uniform series with entire series equivalent to P.

Single Payment Present Worth Factor (PWF). To determine the present worth of a future single expenditure, multiply the future expenditure by PWF. For example, the present worth of $1,000 spent three years from the beginning of the study period, with an interest rate, or present worth discount rate, of 12 per cent would be calculated as follows.

$$PWF = \frac{1}{(1+i)^n} = \frac{1}{(1.12)^3} = .7118$$

Present Worth = $1,000 X .7118 = $711.80

Uniform Series Present Worth Factor (USPWF). To determine the present worth of a uniform series of payments, multiply the payment by USPWF. For example, find the present worth of a series of 5 annual payments, each equal to $500, with the first payment occurring one year from the beginning of the study period. Assume a present worth discount rate of 12 per cent.

$$USPWF = \frac{1 - \frac{1}{(1+i)^n}}{i} = \frac{1 - \frac{1}{(1.12)^5}}{.12} = 3.6048$$

Present worth = $500 X 3.6048 = $1802.40

Capital Recovery Factor (CRF). Given a present sum of money, to find the constant amount payable at the end of each year such that the present worth of the uniform series is equal to the present sum, multiply the present sum by CRF. For example, if the present sum is $2,000, find the equal annual payment to be paid for 5 years that will have an equivalent present worth to $2,000. Assume a present worth discount rate of 12 per cent.

$$CRF = \frac{i}{1 - \frac{1}{(1+i)^n}} = \frac{.12}{1 - \frac{.1}{(1.12)^5}} = .27741$$

Equal annual payment = $2,000 X .27741 = $554.82

Tables listing the above factors for many combinations of interest rates and numbers of interest periods can be found in most economic textbooks.

The present worth discount rate for the Intermountain Generating Station is 12.0 per cent applied to one-year periods with July 1, 1986 to June 30, 1987 being the first year. The compound interest factors for 12.0 per cent are listed on Table 41.0100-1. With July 1, 1986 as the base for present worth determinations, the sums of annual present worth factors for Unit 1 and for the station are as follows.

	Evaulation Period	Uniform Series Present Worth Factor
Unit 1	35 years	8.1755
Units 1 and 2	36 Years	8.1924

2. Escalation Rate.

Equipment costs and labor costs have increased steadily for many years and are expected to continue to increase. Escalation results from two principal influences: the decreasing value of the dollar (due to "inflation"), and the effect of reduced supply with respect to demand ("Real escalation"). Total escalation can be expressed in terms of its two components by the following equation:

$(1 + e) = (1 + e_r)(1 + j)$, where

e = total escalation rate, decimal

e_r = real escalation rate, decimal

j = inflation rate, decimal

The following terminology is used in discussing various aspects of escalation.

Escalation Rate--The total escalation rate, sometimes called "apparent escalation rate," that includes both inflation and real escalation.

Inflation Rate--The annual rate of increase in the general price level of all goods and services which results in a decreased value of the dollar over time. Government indices used to quantify inflation are the Gross National Product (GNP) implicit price deflator and the Producer Price Index (formerly the Wholesale Price Index).

Real Escalation Rate--The annual rate of increase in the price of a particular product or service, independent of inflation. Factors that cause real escalation include resource depletion, reduced productivity, increased demand, and increased government regulation.

TABLE 41.0100-1. 12.0 PER CENT COMPOUND INTEREST FACTORS

		Single Payment		Uniform Series			
n	Year Starting July 1	Compound Amount Factor $(1+i)^n$	Present Worth Factor $\frac{1}{(1+i)^n}$	Sinking Fund Factor $\frac{i}{(1+i)^n-1}$	Capital Recovery Factor $\frac{i(1+i)^n}{(1+i)^n-1}$	Compound Amount Factor $\frac{(1+i)^n-1}{i}$	Present Worth Factor $\frac{(1+i)^n-1}{i(1+i)^n}$
1	1986	1.1200	.8929	1.0000	1.1200	1.0000	.8929
2	1987	1.2544	.7972	.4717	.5917	2.1200	1.6901
3	1988	1.4049	.7118	.2963	.4163	3.3744	2.4018
4	1989	1.5735	.6355	.2092	.3292	4.7793	3.0373
5	1990	1.7623	.5674	.1574	.2774	6.3528	3.6048
6	1991	1.9738	.5066	.1232	.2432	8.1152	4.1114
7	1992	2.2107	.4523	.0991	.2191	10.0890	4.5638
8	1993	2.4760	.4039	.0813	.2013	12.2997	4.9676
9	1994	2.7731	.3606	.0677	.1877	14.7757	5.3282
10	1995	3.1058	.3220	.0570	.1770	17.5487	5.6502
11	1996	3.4786	.2875	.0484	.1684	20.6546	5.9377
12	1997	3.8960	.2567	.0414	.1614	24.1331	6.1944
13	1998	4.3635	.2292	.0357	.1557	28.0291	6.4235
14	1999	4.8871	.2046	.0309	.1509	32.3926	6.6282
15	2000	5.4736	.1827	.0268	.1468	37.2797	6.8109
16	2001	6.1303	.1631	.0234	.1434	42.7533	6.9740
17	2002	6.8660	.1456	.0205	.1405	48.8837	7.1196
18	2003	7.6900	.1300	.0179	.1379	55.7497	7.2497
19	2004	8.6128	.1161	.0158	.1358	63.4397	7.3658
20	2005	9.6463	.1037	.0139	.1339	72.0524	7.4694
21	2006	10.8038	.0926	.0122	.1322	81.6987	7.5620
22	2007	12.1003	.0826	.0108	.1308	92.5026	7.6446
23	2008	13.5523	.0738	.0096	.1296	104.6029	7.7184
24	2009	15.1786	.0659	.0085	.1285	118.1552	7.7843
25	2010	17.0001	.0588	.0075	.1275	133.3339	7.8431
26	2011	19.0401	.0525	.0067	.1267	150.3339	7.8957
27	2012	21.3249	.0469	.0059	.1259	169.3740	7.9426
28	2013	23.8839	.0419	.0052	.1252	190.6989	7.9844
29	2014	26.7499	.0373	.0047	.1247	214.5828	8.0218
30	2015	29.9599	.0334	.0041	.1241	241.3327	8.0552
31	2016	33.5551	.0298	.0037	.1237	271.2926	8.0850
32	2017	37.5817	.0266	.0033	.1233	304.8477	8.1116
33	2018	42.0915	.0238	.0029	.1229	342.4294	8.1354
34	2019	47.1425	.0212	.0026	.1226	384.5210	8.1566
35	2020	52.7996	.0189	.0023	.1223	431.6635	8.1755
36	2021	59.1356	.0169	.0021	.1221	484.4631	8.1924
37	2022	66.2318	.0151	.0018	.1218	543.5987	8.2075
38	2023	74.1797	.0135	.0016	.1216	609.8305	8.2210
39	2024	83.0812	.0120	.0015	.1215	684.0102	8.2330
40	2025	93.0510	.0107	.0013	.1213	767.0914	8.2438

Note: i = interest rate per interest period
n = number of interest periods

Actual Dollars--The expected cost with the effect of inflation included, sometimes called current dollars. It reflects the actual out-of-pocket cost that one would expect to pay for the goods or services being considered in a particular year.

Real Dollars--The expected cost with the effect of inflation removed, sometimes called constant dollars. These dollar amounts should be expressed in terms of a certain year, for example, in 1986 dollars.

Calculations of escalated costs are usually made by annual compounding. Sometimes, it is necessary to escalate costs on a monthly rather than an annual basis. The monthly escalation rate is computed by the following formula:

$$(1 + e_m) = (1 + e)^{1/12}, \text{ where}$$

e_m = monthly escalation rate, decimal

e = annual escalation rate, decimal

For large projects such as power plants, it is usually assumed for simplicity that the entire cost of the project is spent as a lump sum at the midpoint of the construction period. As an example, for large coal-fired power plants the construction period is normally assumed to be approximately four years, so escalation for such plants is computed until about two years before the scheduled date for commercial operation.

The anticipated Intermountain Generating Station escalation rate for equipment and materials are as follows.

		Escalation Rate	
Item	Period	Compounded Yearly per cent	Compounded Monthly per cent
	1/1/83 to 12/31/89	8.3	0.6667
	1/1/90 and thereafter	7.0	0.5654

In most cases, escalated direct capital costs of equipment and materials will be the costs anticipated to be in effect two years before commercial operation which is considered to be the mid-point of the construction period. For example, direct capital costs for Unit 1 will be determined as of July 1, 1984.

3. Indirect Costs.

Capital cost estimates for power plants include an item for indirect costs which is usually calculated as a percentage of escalated direct costs. The direct costs consist of total costs for each contract. Contract costs comprise costs for procurement of equipment and materials, installation, and general construction.

Indirect costs include expenses for engineering services, field construction management services, and Owner costs.

Indirect capital costs for the Intermountain Generating Station are 14 per cent of direct capital costs. Indirect capital costs include engineering, construction management, and Owner legal, administrative, and overhead costs.

4. Allowance for Funds Used During Construction (AFUDC).

The interest paid on money spent to construct a power plant is called Allowance for Funds Used During Construction; it is usually abbreviated AFUDC.

AFUDC is calculated for payments made during the time from the start of the project until the commercial operation date and is listed as a separate cost account in the total capital cost of the plant.

AFUDC is calculated by the following method which is used when information on payment and delivery dates is not available. Assume that all payments are made in a lump sum at the midpoint of the construction period and calculate the interest from the midpoint of the construction period until the date of commercial operation. This method is normally used in cost estimates for systems analyses, and it is also used for preliminary total plant cost estimates. The length of the construction period increases with the size and complexity of the project; for large coal-fired pwoer plants, it is normally assumed to be about four years.

An allowance for funds used during construction is applied to the direct capital cost of equipment and materials after adjustments for indirect costs, and escalation. For the Intermountain Generation Station the AFUDC rate starting in 1983 and thereafter is 1.0095 per cent compounded monthly which is equivalent to 12.0 per cent compounded annually. Typically, the AFUDC rate will be applied for a two-year period and AFUDC will be $[(1.12)^2 -1]$ or 25.44 per cent.

5. Capital Equivalent Cost Method

This method is used to compare alternative plans on the basis of total capital equivalent cost. The operating costs are expressed as a capital equivalent and added to the capital cost to obtain a total capital equivalent cost.

The capital equivalent operating costs are determined by dividing the levelized costs by the levelized annual fixed charge rate.

The Intermountain Generating Station levelized annual fixed charge rate, based on a generating unit life of 36 years and a zero net salvage value, is 13.19 per cent.

The total capital equivalent cost is the sum of the original capital cost and the capital equivalent cost of the operating cost.

6. Replacement Power Costs During Delays.

Estimated differential fuel costs are the estimated differences between the cost of coal used at the Intermountain Generating Station and the marginal cost of fuels required to generate electrical energy at other facilities that would be used if all or part of the Intermountain Generating Station were out of service. The replacement power costs for the Intermountain Generating Station is estimated to be $750,000 per day for each unit.

Inclusion of other charges for replacement energy, such as those for operating and maintenance, is not appropriate for this Project.

Appendix B - Smaple Calculation to Illustrate Effect of 95 per cent SO_2 removal on project cost.

BLACK & VEATCH CONSULTING ENGINEERS

Owner INTERMOUNTAIN POWER PROJECT
Plant INTERMOUNTAIN GEN. STATION Unit 1 & 2
Project No. 9255 File No.
Title SAMPLE CALCULATION TO ILLUSTRATE EFFECT OF 95% SO_2 REMOVAL ON PROJECT COSTS

Computed By J. R. COCHRAN
Date NOV 19 1983
Checked By J. M. GUSTKE
Date 5-23 1983

THIS EXAMPLE CALCULATION IS BASED ON INCREASING THE SO_2 REMOVAL EFFICIENCY REQUIREMENT FROM 90 PER CENT TO 95 PER CENT ON A ROLLING 30-DAY AVERAGE.

UNITS 1 AND 2 OF THE INTERMOUNTAIN GENERATING STATION ARE CURRENTLY SCHEDULED FOR STARTUP IN JUNE 1986 AND JUNE 1987 RESPECTIVELY. THE CURRENT CONTRACT COSTS FOR THE IGS UNITS 1 & 2 ARE AS FOLLOWS.

	CONTRACT COSTS (AS SPENT BASIS) (10^6 \$)
UNIT 1	2089
UNIT 2	1254
TOTAL	3343

THESE CONTRACT COSTS ARE IN "AS-SPENT" DOLLARS AND ARE ASSUMED TO BE ESCALATED TO THE MID-POINT OF CONSTRUCTION. THE MID-POINTS OF CONSTRUCTION ARE JUNE 1984 AND JUNE 1985 FOR UNITS 1 AND 2 RESPECTIVELY. TO CONVERT THESE CONTRACT COSTS INTO A CONSISTENT SET OF JUNE 1983 CAPITAL COSTS IT WILL BE NECESSARY TO DE-ESCALATE THESE CONTRACT COSTS BY 8.3 % PER YEAR:

	CAPITAL COSTS (10^6 \$)	
UNIT 1	1930	\$6/83
UNIT 2	1069	
TOTAL	2999	

THESE DIRECT COSTS INCLUDE SALES TAX WHERE APPLICABLE. DIRECT COSTS CONSIST OF TOTAL COSTS FOR EACH CONTRACT, INCLUDING PROCUREMENT OF EQUIPMENT AND MATERIALS, INSTALLATION, AND GENERAL CONSTRUCTION.

DO NOT WRITE IN THIS SPACE

P-GN-172A

BLACK & VEATCH CONSULTING ENGINEERS		
Owner: INTERMOUNTAIN POWER PROJECT		Computed By: [illegible]
Plant: INTERMOUNTAIN GEN. STATION	Unit: 1 & 2	Date: 5/20 1983
Project No. 9255	File No.	Checked By: JMG
Title: SAMPLE CALCULATION TO ILLUSTRATE EFFECT OF 95% SO_2 REMOVAL ON PROJECT COSTS		Date: 5-26 1983
		Page 2 of

THE INCREMENTAL CAPITAL COST (JUNE 1983 DOLLARS) OF INCREASING THE SO_2 REMOVAL EFFICIENCY FROM 90 TO 95 PER CENT ARE AS FOLLOWS.

	INCREMENTAL CAPITAL COST (10^6 \$)	
UNIT 1	35.3	NO SALES TAX
UNIT 2	35.3	
TOTAL	70.6	

INDIRECT CAPITAL COSTS FOR THE IGS ARE 14 PER OF DIRECT CAPITAL COSTS. INDIRECT CAPITAL COSTS INCLUDE ENGINEERING, CONSTRUCTION MANAGEMENT, AND OWNER LEGAL, ADMINISTRATIVE, AND OVERHEAD COSTS. THE INDIRECT COSTS FOR THE BASE PLUS INCREMENTAL EXPENDITURES ARE AS FOLLOWS.

	DIRECT CAPITAL COST (10^6 \$)	INCREMENTAL CAPITAL COST (10^6 \$)	DIRECT CAPITAL COST (10^6 \$)	INDIRECTS (10^6 \$)	1983 CAPITAL COST (10^6 \$)
UNIT 1	1930	35.3	1965.3	275.1	2240.4
UNIT 2	1069	35.3	1104.3	154.6	1258.9
TOTAL	2998	70.6	3069.6	429.7	3499.3

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BLACK & VEATCH CONSULTING ENGINEERS		
Owner INTERMOUNTAIN POWER PROJECT		Computed By [signature]
Plant INTERMOUNTAIN GEN. STATION	Unit 1 & 2	Date 5/20 1983
Project No. 9255	File No.	Checked By JMG
Title SAMPLE CALCULATION TO ILLUSTRATE EFFECT OF 95% SO_2 REMOVAL ON PROJECT COSTS		Date 5-23 1983
		Page 3 of 11

THE STARTUP OF UNITS 1&2 WILL BE DELAYED 18 MONTHS IF THE DECISION TO DESIGN IGS UNITS FOR 95% SO_2 REMOVAL WERE MADE. THESE CHANGES WILL AFFECT THE MID-POINT OF CONSTRUCTION BY APPROXIMATELY HALF OF THE PROJECT DELAY.
THE ADJUSTED MILESTONE DATES WOULD BE AS FOLLOWS.

	Delayed MID POINT OF CONSTRUCTION	Delayed UNIT STARTUP
UNIT 1	MARCH 1985	DECEMBER 1987
UNIT 2	MARCH 1986	DECEMBER 1988

FOR PURPOSES OF THIS EVALUATION IT WILL BE ASSUMED THAT ALL PAYMENTS ARE MADE IN A LUMP SUM AT THE MIDPOINT OF THE CONSTRUCTION PERIOD. IT WILL THEN BE NECESSARY TO ESCALATE CALCULATED 1983 CAPITAL COSTS TO THE MID-POINT OF CONSTRUCTION. CAPITAL COSTS ARE EXPECTED TO ESCALATE AT AN ANNUAL RATE OF 8.3%, AS OF JUNE 1983, $400,000,000 WILL HAVE BEEN SPENT ON UNIT 1. MONEY ALREADY SPENT ON THE PROJECT WILL NOT BE ESCALATED TO THE MID-POINT OF CONSTRUCTION.

	1983 CAPITAL COST (10^6 $)	REMAINING EXPENDITURES (10^6 $)	ESCALATION TO THE MID-POINT OF CONSTR. (10^6 $)	MID-POINT CAPITAL COST (10^6 $)
UNIT 1	2240.4	1840.4	275.6	2516.0
UNIT 2	1258.9	1258.9	309.6	1567.5
		TOTAL =	584.2	

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REVISED, SUPERSEDED, AND VOID CALCULATIONS MUST BE CLEARLY IDENTIFIED, INITIALED, AND DATED BY THE RESPONSIBLE INDIVIDUAL

BLACK & VEATCH
CONSULTING ENGINEERS

Owner: IPP
Plant: IGS   Unit: 1 & 2
Project No. 9255   File No.
Title: Sample Calculation to Illustrate Effect of 95% SO_2 Removal on Project Costs

Computed By: [signature]
Date: 5/20 1983
Checked By: JMG
Date: 5-23 1983
Page 4 of 11

THE INTEREST PAID ON MONEY SPENT TO CONSTRUCT UNITS 1 & 2 IS CALLED ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC). AFUDC IS CALCULATED FOR PAYMENTS MADE DURING THE PERIOD FROM THE START OF THE PROJECT UNTIL THE COMMERCIAL OPERATION DATE AND IS LISTED AS A SEPARATE COST ACCOUNT IN THE TOTAL CAPITAL COST OF THE PLANT. AFUDC FOR THE IGS UNITS WILL BE CALCULATED AT 12% PER YEAR FROM THE MID-POINT TO THE END OF CONSTRUCTION. FOR FUNDS ALREADY COMITTED, AFUDC WILL BE CALCULATED FROM THE EXPENDITURE DATE TO THE END OF CONSTRUCTION. AFUDC FOR UNIT 1 WILL BE CALCULATED FROM 3/1985 TO 12/1987 EXCLUDING THE \$400,000,000 ALREADY SPENT. AFUDC ON \$400,000,000 ALREADY SPENT IS CALCULATED FROM 6/1983 TO 12/1987. AFUDC FOR UNIT 2 IS FROM 3/1986 TO 12/1988.

AFUDC on Funds Already Committed = $400(1.12^{4.5}-1) = 266.1\ (10^6\$)$

	Mid-Point Capital Cost (10^6\$)	Remaining Expenditures (10^6\$)	AFUDC on Remaining Expenditures (10^6\$)
Unit 1	2516.0	2116.0	773.8
Unit 2	1567.5	1567.5	573.2
		Total AFUDC =	1347.0

AFUDC Rate $= (1.12^{2.75}-1) = 0.3675$

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REVISED, SUPERSEDED, AND VOID CALCULATIONS MUST BE CLEARLY IDENTIFIED, INITIALED, AND DATED BY THE RESPONSIBLE INDIVIDUAL

BLACK & VEATCH
CONSULTING ENGINEERS

Owner IPP
Plant IGS Unit 1 & 2
Project No. 9255 File No.
Title Sample Calculation to Illustrate Effect of 95% SO_2 Removal on Project Costs

Computed By [signature]
Date 5/20 1982
Checked By JMG
Date 5-25 1982

Therefore the comparative capital costs for IGS Units 1 & 2 are as follows

	Unit 1 (10^6 \$)	Unit 2 (10^6 \$)	Unit 1 & 2 (10^6 \$)
Base Capital Cost	1930.0	1069.0	2999.0
Incremental Capital Cost	35.3	35.3	70.6
Direct Capital Investment	1965.3	1104.3	3069.6
Indirects	275.1	154.6	429.7
June 1983 Capital Cost	2240.4	1258.9	3499.3
Escalation to Mid-Point of Constr.	275.6	308.6	584.2
Mid-Point Capital Cost	2516.0	1567.5	4083.5
AFUDC - Funds Already Committed	266.1	-	266.1
- on Remaining Expenditures	773.8	573.2	1347.0
Total Capital Costs			
Unit 1 12/87 \$	3555.9		
Unit 2 12/88 \$		2140.7	5696.6

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REVISED, SUPERSEDED, AND VOID CALCULATIONS MUST BE CLEARLY IDENTIFIED, INITIALED, AND DATED BY THE RESPONSIBLE INDIVIDUAL.

BLACK & VEATCH
CONSULTING ENGINEERS

Owner TPC
Plant TGS Unit 1 & 2
Project No. 9255 File No.
Title Sample Calculation to Illustrate Effect of 95% SO_2 Removal on Project Costs

Computed By [illegible]
Date 5/20 1983
Checked By JMG
Date 5-25 1983

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To get capital costs onto a consistent basis it will be necessary to present worth costs back to June 1986 dollars. The present worth discount rate is 20% per year. The present worth factor is calculated using the following formula.

$$\text{Present Worth Factor} = \frac{1}{(1 + \text{PWDR})^n}$$

Where PWDR is the Present Worth Discount Rate.

Therefore the June 1986 Units 1 & 2 Capital Costs would be as follows.

	Total Capital Cost	Discount Years	Present Worth Factor	June 1986 Present Worth of Total Capital Costs
Unit 1	3555.9	1.5	0.844	3000.0
Unit 2	2140.7	2.5	0.753	1612.6
Total				4612.6

P-GN-172A

REVISED, SUPERSEDED, AND VOID CALCULATIONS MUST BE CLEARLY IDENTIFIED, INITIALED, AND DATED BY THE RESPONSIBLE INDIVIDUAL

BLACK & VEATCH
CONSULTING ENGINEERS

Owner: IPP
Plant: IGS   Unit: 1 & 2
Project No.: 9255   File No.:
Title: Sample Calculation to Illustrate Effect of 95% SO_2 Removal on Project Costs

Computed By: [illegible]
Date: 5/21 1983
Checked By: JMG
Date: 5-26 1983

CAPITALIZED VALUE OF OPERATING COSTS

ECONOMIC CRITERIA:

FIXED CHARGE RATE = 13.19%
LEVELIZATION FACTOR = 1.511
CAPACITY FACTOR = 72.1%

ESCALATION RATE = 8.3%
Pres. WORTH. DISC. RATE = 12.0%

TO PROPERLY OPERATE AND MAINTAIN THE SO_2 REMOVAL EQUIPMENT IT WILL TAKE SIGNIFICANTLY MORE OPERATING PERSONNEL. IT WAS ESTIMATED TO TAKE APPROXIMATELY 5 EXTRA WORKERS TO OPERATE AND MAINTAIN EQUIPMENT EXPECTED TO MAINTAIN THE 95% SO_2 REMOVAL REQUIREMENT. THE 1986 COST OF LABOR WILL BE APPROXIMATELY 48000 \$/man-year. THEREFORE, THE 1986 CAPITALIZED COST FOR UNITS 1 & 2 WOULD BE AS FOLLOWS.

DIFFERENTIAL
1986 CAPITALIZED COSTS
FOR OPERATING PERSONNEL

$$\text{UNIT 1} = \frac{\left(5 \frac{\text{man years}}{\text{year}}\right)\left(48000\ \$/\text{man year}\right)(1.511)}{(0.1319)} = \$2700 \times 10^3$$

ONE YEAR LATER FOR UNIT 2

$$\text{UNIT 2} = 2700 \times 10^3 \left(\frac{1.083}{1.12}\right) = \$2600 \times 10^3$$

DO NOT WRITE IN THIS SPACE

P-GN-172A

REVISED, SUPERSEDED, AND VOID CALCULATIONS MUST BE CLEARLY IDENTIFIED, INITIALED, AND DATED BY THE RESPONSIBLE INDIVIDUAL

MAINTENANCE COSTS WOULD ALSO INCREASE TO ATTAIN THE DESIRED 95% SO_2 REMOVAL. IT IS ESTIMATED THAT THE 1986 INCREASED MAINTENANCE COST WOULD BE 2,780,000 \$/YR. THEREFORE, THE 1986 CAPITALIZED COST FOR UNITS 1 & 2 WOULD BE AS FOLLOWS.

DIFFERENTIAL
1986 CAPITALIZED COSTS
FOR MAINTENANCE

$$\text{UNIT 1} = \frac{(2{,}780{,}000\ \$/\text{YEAR})(1.511)}{(0.1319)} = \$31{,}900 \times 10^3$$

ONE YEAR LATER FOR UNIT 2

$$\text{UNIT 2} = 31900\left(\frac{1.083}{1.12}\right) = \$30{,}800 \times 10^3$$

IT TAKES SUBSTANTIALLY MORE EQUIPMENT OPERATING TO MAINTAIN 95% SO_2 REMOVAL OVER 90% REMOVAL. ADDITIONAL EQUIPMENT WILL CREATE A DEMAND PENALTY OF APPROXIMATELY 5 MW. THE 1986 DEMAND CHARGE FOR THE IGS IS 600 \$/kW. THEREFORE THE 1986 CAPITALIZED COSTS FOR UNITS 1 & 2 WOULD BE AS FOLLOWS,

DIFFERENTIAL
1986 CAPITAL COSTS
FOR INCREASED DEMAND

$$\text{UNIT 1} = \text{UNIT 2} = \frac{(5000\ \text{kW})(600\ \$/\text{kW})(1.511)}{0.1319} = \$34{,}400 \times 10^3$$

BLACK & VEATCH CONSULTING ENGINEERS		
Owner IPP		Computed By [signature]
Plant IGS	Unit 1 & 2	Date 5/12 1983
Project No. 9255	File No.	Checked By JMG
Title SAMPLE CALCULATION TO ILLUSTRATE EFFECT OF 95% SO_2 REMOVAL ON PROJECT COSTS		Date 5-25 1983
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IN THIS SPACE DO NOT WRITE

ADDITIONAL EQUIPMENT ALSO REQUIRES MORE ENERGY. IT WILL TAKE APPROXIMATELY ADDITIONAL AMOUNT OF 16,800 MWH/YEAR TO RUN THE ADDITIONAL EQUIPMENT AT A 1986 COST OF ENERGY OF 0.03479 $/kWh. THEREFORE THE 1986 CAPITALIZED COST OF DIFFERENTIAL ENERGY WOULD BE AS FOLLOWS.

DIFFERENTIAL
1986 CAPITAL COSTS
FOR ADDITIONAL ENERGY NEEDS

$$\text{UNIT 1} = \frac{(16{,}800{,}000 \tfrac{\text{kWh}}{\text{Year}})(0.03479 \$/\text{kWh})(1.511)}{0.1319} = \$6700 \times 10^3$$

ONE YEAR LATER FOR UNIT 2

$$\text{UNIT 2} = 6700 \times 10^3 \left(\frac{1.083}{1.12}\right) = \$6500 \times 10^3$$

INCREASED SO_2 REMOVAL REQUIREMENTS WILL INCREASE LIMESTONE USAGE. TO INCREASE FROM 90% TO 95% SO_2 REMOVAL WILL REQUIRE APPROXIMATELY 6200 tons/YEAR ADDITIONAL LIMESTONE AT A 1986 COST OF 8.50 $/ton. THEREFORE THE 1986 CAPITALIZED COST OF DIFFERENTIAL LIME USAGE WOULD BE AS FOLLOWS.

DIFFERENTIAL
1986 CAPITAL COSTS
FOR ADDITIONAL LIME USAGE

$$\text{UNIT 1} = \frac{(6200 \text{ tons/YEAR})(8.50 \$/\text{ton})(1.511)}{0.1319} = \$600 \times 10^3$$

ONE YEAR LATER FOR UNIT 2

$$\text{UNIT 2} = 600\left(\frac{1.083}{1.12}\right) = \$600 \times 10^3$$

REVISED, SUPERSEDED, AND VOID CALCULATIONS MUST BE CLEARLY IDENTIFIED, INITIALED, AND DATED BY THE RESPONSIBLE INDIVIDUAL

P-GN-172A

BLACK & VEATCH CONSULTING ENGINEERS

Owner TOD
Plant IGS Unit 1 & 2
Project No. 9255 File No.
Title SAMPLE CALCULATION TO ILLUSTRATE EFFECT OF 95% SO_2 REMOVAL ON FIXED COST

Computed By
Date 5-21 1983
Checked By JMG
Date 5-26 1983

TO ENHANCE THE SO_2 REMOVAL EFFICIENCY IT WILL BE NECESSARY TO USE ADIPIC ACID. TO MAINTAIN A 95% REMOVAL EFFICIENCY IT WILL TAKE APPROXIMATELY 760,000 lb/YR OF ADIPIC ACID AT A 1986 COST OF 0.87 \$/lb. THEREFORE THE 1986 CAPITALIZED COST OF ADIPIC ACID WOULD BE AS FOLLOWS.

1986 CAPITAL COSTS FOR ADIPIC ACID USAGE

$$\text{UNIT 1} = \frac{(760{,}000\ \text{lb/YR})(0.87\ \$/\text{lb})(1.511)}{(0.1219)} = \$7600\times10^3$$

ONE YEAR LATER FOR UNIT 2

$$\text{UNIT 2} = 7600\times10^3\left(\frac{1.083}{1.12}\right) = \$7300\times10^3$$

SUMMING THE SPECIFIC CAPITALIZED ANNUAL COSTS OF OPERATION YIELDS THE FOLLOWING TOTALS.

	UNIT 1 (10^3 \$)	UNIT 2 (10^3 \$)	UNIT 1 & 2 (10^3 \$)
OPERATING PERSONNEL	2700	2600	5300
MAINTENANCE	31900	30800	62700
DEMAND	34400	34400	68800
ENERGY	6700	6500	13200
LIMESTONE ADDITIVE	600	600	1200
ADIPIC ACID	7600	7300	14900
TOTAL CAPITALIZED OPERATING COST	83,900	82,200	166,100

P-GN-172A

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BLACK & VEATCH
CONSULTING ENGINEERS

Owner: IPD
Plant: IGS — Unit:
Project No. 9255 — File No.
Title: Sample Calculation to Illustrate Effect of 95% SO_2 Removal on Project Costs

Computed By: Gal — Date: 5/21 1983
Checked By: JMG — Date: 5-23 1983
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Replacement Power Costs Due to Delay

The 1986 cost of replacement power is 750,000 \$/Day of Delay. Units 1 & 2 will each be delayed 18 months to make design changes necessary to upgrade the removal efficiency of the SO_2 Removal System. If there are 30 Days/Month the Replacement Power Costs will be as follows.

$$\text{Unit 1} = \text{Unit 2} = (750{,}000\ \$/\text{Day})(18\ \text{Months})(30\ \text{Days}/\text{Month}) = \$\,405 \times 10^6$$

Therefore the total cost of the 95% SO_2 Removal Alternative would be as follows.

	Unit 1 (10^6\$)	Unit 2 (10^6\$)	Unit 1&2 (10^6\$)
Present Worth of Total Capital Costs	3000.0	1612.6	4612.6
Capitalized Value of Annual Operating Costs	83.9	82.2	166.1
Replacement Power Costs Due to Delay	405.0	405.0	810.0
Total Cost of Alternative (1986 Dollars)	3488.9	2099.8	5588.7

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